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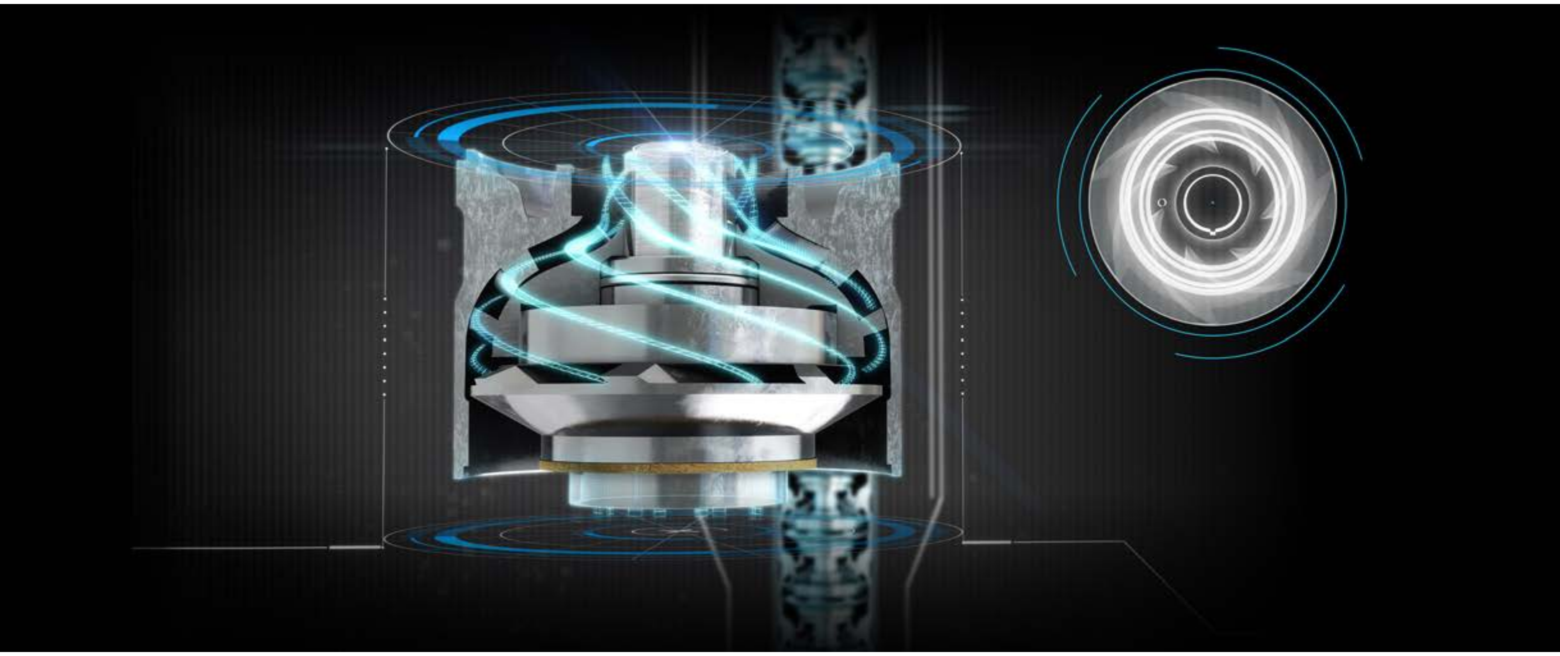
SPECIAL FOCUS: ARTIFICIAL LIFT ADVANCES

Extended-life ESP reliably accommodates wide, abrasive production range in remote brownfield



A mature field in Ecuador posed a range of challenges that threatened its long-term economics. Extended-life ESPs, combined with remote real-time surveillance, were a viable solution to handle gassy, sandy wells with steep production decline, saving $2.5 million in workover costs.

■ JORGE LUIS VILLALOBOS LEON and CARLOS REYES HILL, Schlumberger

Electric submersible pumps (ESPs) are well-known as effective secondary recovery strategy solutions. Until recently, however, their individual drawbacks have required an operator to use multiple, if not dozens, of individual ESPs to handle various reservoir challenges.

Abrasive production content, high downhole reservoir temperatures, deep setting depths, extended run times, and a broad production envelope were faced during secondary recovery in a conventional well in the Oriente basin of Ecuador. New REDA Continuum* extended-life ESP pumps—combined with a remote, real-time surveillance workflow—handled all of these requirements and enabled long-term field success.

Extended-life ESPs, used in conjunction with real-time surveillance, have increased ESP reliability in the field and reduced downtime.

ESP DESIGN EVOLUTION

A good example of ESPs' iterative improvement is presented by Pastre and Fastovets (2017). They reviewed how, over 30 years, a North Sea field began producing with increased water cut, scale deposition, and sand production. Initial failure analysis determined that unexpectedly high sand production caused the original mechanical systems to fail. In turn, the manufacturer reengineered the ESP with harder stage material and bearings. Later, however, shaft stability caused failure, thus spurring a pattern—each failure sparked a new round of design improvement.

Simultaneously, surveillance services and surface controllers have rapidly evolved to provide operators with real-time insight into production performance. Combined with these smart surveillance methodologies, ESP systems began delivering beyond the requirements they were originally introduced to meet, and in environments far more demanding than early field developers anticipated.

The incremental design improvements that made the ESP ideal for artificial lift in the North Sea became the backbone of a new technology optimized for today's most challenging—and varied—production environments.

CHALLENGING PARAMETERS IN THE ORIENTE BASIN

One such challenging environment is the mature fields of the Oriente basin, onshore Ecuador. There are four main producing formations in the basin, located between 8,500-ft and 10,000-ft depths. The reservoir drive mechanisms for three layers are rock compaction as pore fluid volumes are depleted, solution gas drive, and weak waterdrive. Consequently, these reservoirs experience rapid pressure depletion and low recovery factors.

The main drive mechanism for one layer is a water drive derived from an infinite, active bottom aquifer. In contrast, the other three layers showed rapid reservoir pressure depletion, due to lack of pressure support from the reservoir drive mechanisms. Formation pressure reached values very close to bubblepoint pressure. This behavior demonstrates the need for a secondary recovery strategy, such as water injection, to provide pressure support to increase the recovery factor.

The field utilized ESPs as its artificial lift system. The current infrastructure presented the opportunity for further enhancement in its functionality to optimize field operation and production. The secondary recovery strategy with waterflooding was implemented to increase reservoir pressure. It included new challenges for the artificial lift system that had to be addressed.

First, a well-to-well injection system had to be put in place; it uses an artificial lift system to produce water from one layer of the aquifer. Then, special design requirements had to be considered, to deliver an ESP with a wide range of production. It required wellhead pressure to achieve the injection rates and pressures (up to 2,500 psi) required by the waterflooding strategy. The compatibility of the injected water and producer reservoir was evaluated, so no chemical treatment was required.

For the oil production wells, some improvements had to be implemented in the ESP to comply with the need for a wide range of flowrate operation; to handle an increase in solids due to fines migration; and to handle gas production, which is common when bottomhole flowing pressure (P_{wf}) falls below the bubblepoint pressure.

Finally, artificial lift downhole monitoring and surveillance were key to increasing ESP reliability and minimize downtime. Monitoring and surveillance were applied, together with a production optimization workflow, to maximize oil production and achieve the required flowrates and P_{wf} from the waterflooding strategy.

ENHANCING SOLUTIONS TO FIT BASIN REQUIREMENTS

Economically extending the productive life of mature fields brings significant challenges. To improve economics of production decline, the artificial lift system needs increased lifting capacity and improved capabilities for handling fines and solids migration. This is because drawdown needs to increase, which means the bottomhole flowing pressure needs to be lowered to facilitate fluid mobilization to the wellbore. In turn, this leads to increased gas production and associated challenges caused by bottomhole flowing pressure going under the bubblepoint pressure.

In contrast, waterflooding strategies

Fig. 1. Production profile of Well A, presenting a strong production decline.

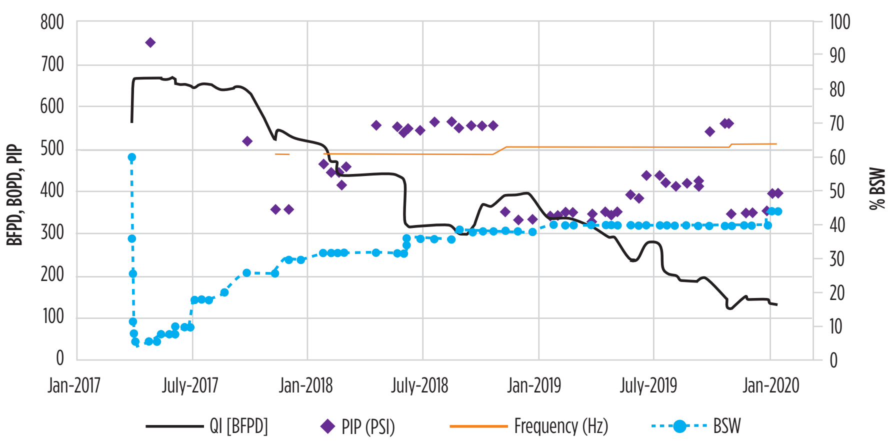


Fig. 2. Production profile from Well B, which started production at 300 bpd and, thanks to waterflooding, reached 1,000 bpd.

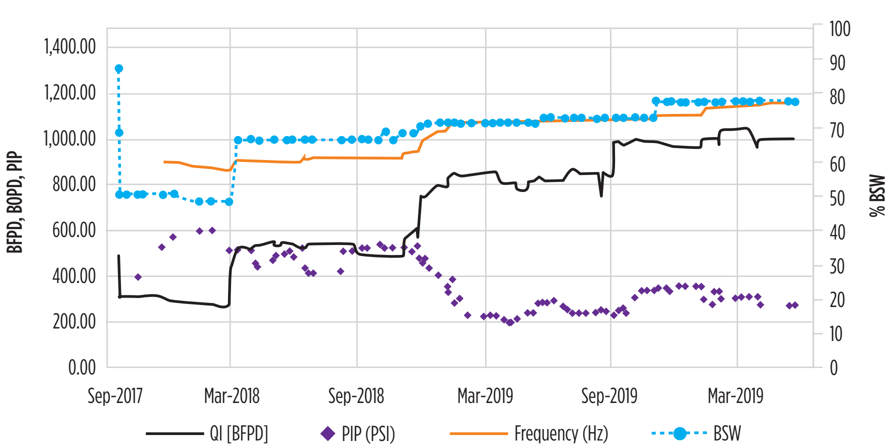
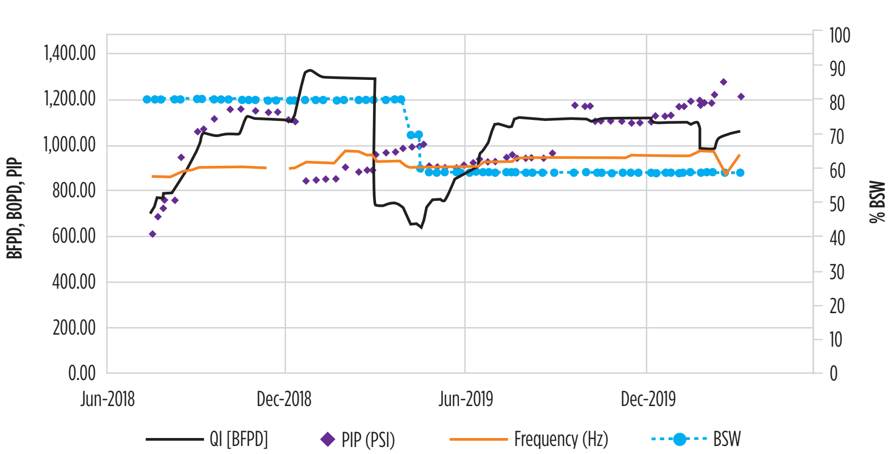


Fig. 3. Production profile of Well C, showing production variation in response to waterflooding.



bring additional challenges and requirements. The ESP system needed to have a wide flowrate operating range. This is to compensate for the inherent uncertainty faced during the production ramp-up, as the reservoir drive mechanisms receive support and additional formation fines migrate to the production wells.

In this field in the Oriente basin, a secondary recovery project was applied in a reservoir with the following conditions:

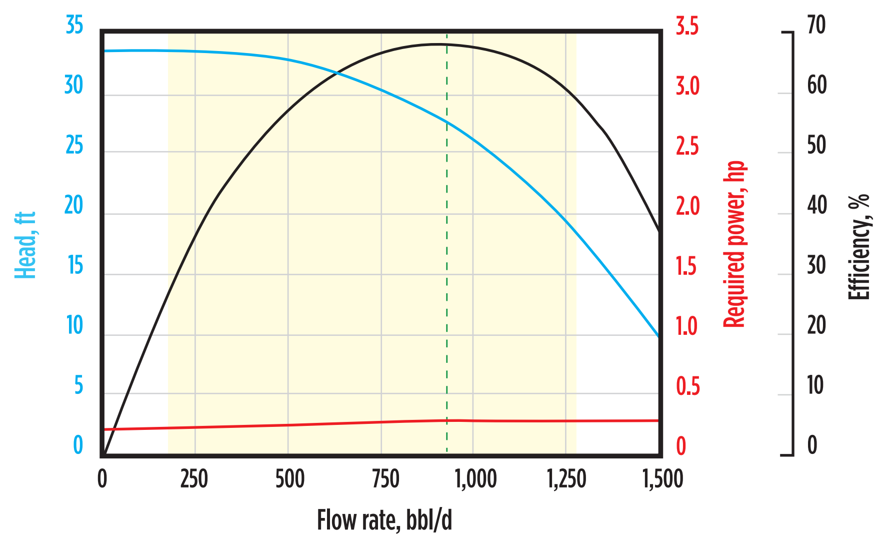
- Deep pump setting depth between 9,000 ft and 10,000 ft, MD
- High bottomhole temperatures (BHTs) between 225° and 240°F
- Migration of fines, solids, and abrasive and corrosive production content from the reservoir
- High gas/oil ratio
- Productivity uncertainty
- Low reservoir production, requiring a reasonably priced ESP
- Remote location in the Ecuadorian jungle, which increased logistical costs for intervention and workover.

These parameters represent unknown challenges for any artificial lift system working under such harsh conditions. Hence, a novel completion system had to be developed. To maximize the field's production potential, the operator needed to implement waterflooding for EOR while avoiding failures. For economic considerations, it was required to reduce the frequency of workovers and ensure the greatest efficiency under different scenarios. Therefore, at the field level, it was critical to design and implement a robust ESP system that covered as wide a production range as possible to minimize the need of pulling operations.

It was clear that the conventional ESP technologies were not satisfactory. The operator in Ecuador was running the conventional technology outside of the ESP's recommended range of flowrates, slugging, and intermittent production. As a result, ESP failure was a frequent occurrence that caused mounting operational costs. They produced with an average run life of only 200 days because of the high BHTs, abrasive solids and gas production, and variable flow with a head requirement of 9,500 ft (2,896 m). Waterflood was not expected to improve those factors.

Today, 60% to 80% of total production is obtained using artificial lift systems. However, most fields are entering into development phases that require different artificial lift types. It is common to use several different artificial lift systems over the life of the well to accommodate varying operational conditions and production phases. There are ESP configurations that can handle more abrasion, more gas, higher BHTs, and other individual scope requirements. But, historically, there was never a single solution that integrated all of these features across an extended operating range. The operator sought this solution to maximize productivity over the entire job.

Fig. 4. General pump curve of the extended-life ESP.



OPERATIONAL FLEXIBILITY FOR BETTER ECONOMIC PERFORMANCE

A secondary recovery strategy with waterflooding not only sweeps hydrocarbons to the oil-producing well, but it also can increase the speed of fines migration. In this field, in the waterflooded areas and reservoirs, the solids content measured in production is between 30 and 100 ppm. Major fines migration issues are expected in the future, as the water sweeps more areas of the reservoir. This is another crucial factor to consider in designing the ESP system.

A number of improvements were implemented in this field, including

- New-generation mixed-flow stages in the extended-life ESP pump
- Enhanced stabilization, with one-third of the stages using tungsten carbide bushings and sleeves
- Compression design for properly distributing the increasing downthrust
- Stage material enhancement to increase the abrasion tolerance.

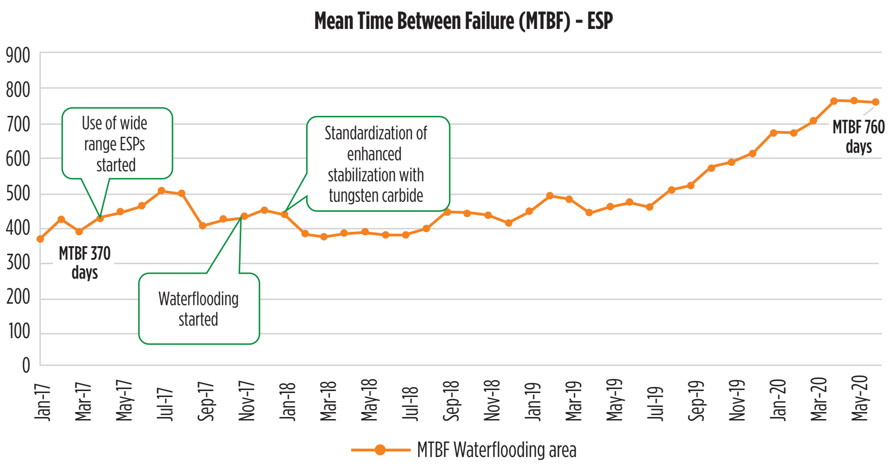
The newly developed, extended-life ESP was introduced to reduce the failure rate, increase uptime, and reduce workover costs. Extended-life ESP pumps are robust enough to produce fluids with high gas-volume fractions and solids content while maintaining high efficiency across a wide production range. Combined with a production life cycle management service that provides real-time monitoring, optimization, and control, the extended-life pumps can handle production in low-flow conditions, to extend run life far beyond that achieved with conventional pumps. In addition to high BHTs, the extended-life ESP was able to efficiently, and reliably, handle abrasive fines, gas flow, and a huge operating range.

MULTIPLE PRODUCTION SCENARIOS EFFICIENTLY HANDLED

Three different applications were tested—decreasing flowrate and activating secondary recovery (Well A); increasing flowrate (Well B); and flow variation (Well C)—and the extended-life ESP successfully handled each.

Well A: Wide-range ESP (300 stages); run time of 1,000 days. Figure 1 shows the production profile of Well A, which presents a strong production decline. The wide-range ESP was able to handle the production decline scenario. The ESP efficiently handled the first month of production, when the well was delivering 670 bpd, and the pump efficiency was 60%. The ESP also performed

Fig. 5. Increased mean time between failure after implementing improvements in extended-life ESP.



robustly at 1,000 days of run life, when the well was producing 150 bpd and the pump efficiency was 18%.

Well B: Wide-range ESP (259 stages); run time of 980 days. Figure 2 shows the production profile of Well B, which started producing 300 bpd. Because of the waterflooding effect, its production reached 1,000 bpd.

Well C: Wide-range ESP (300 stages); run time of 650 days. Figure 3 shows the production profile of Well C, which shows important changes in response to the waterflooding effect. Well C started production at 700 bpd, reached a maximum of 1,300 bpd, then dropped and increased again to finally stabilize production at approximately 1,100 bpd.

Because of reservoir pressure decline, it is crucial to include technologies for gas separation, gas handling, or both when producing below the bubblepoint pressure. Additionally, waterflooding can bring fines into the producer wellbore. These two additional challenges were considered during the selection and design of the artificial lift system.

To overcome these issues, Schlumberger designed the extended-life ESP system with re-engineered mixed-flow stages and an extended operating range. Its compression design properly distributed the increased downthrust, enabling operation outside the flow range. The optimized geometry, architecture, and material selection enabled the ESP to operate with high efficiency from 200 to 1,250 bpd, improving recovery and reliability at low rates and in transient flow. At the time of the implementation, nearly 75% of the wells in the field were producing within that production range. To solve the needs of handling solids and gas, the ESP systems were designed to include gas separators and gas handlers.

Another advantage of the extended-life ESP is that it imparts increased reliability to the system under production-decline scenarios, as well as production ramp-up from waterflooding in the same string. In this context, the system assures that the selected motor could provide enough power to cover the full range of the ESP under 90% motor load. These improvements give the advantage of reducing the number of workover interventions for ESP resizing. Figure 4 shows the curve of the extended-life ESP.

SURVEILLANCE FOR INCREASED RELIABILITY AND PRODUCTION

Early identification of events is mandatory to take the right actions for increasing both ESP reliability and oil production. For that reason, ESP surveillance performance was highly important, because ESPs were the main artificial lift system in this field.

The data from the ESP systems installed in both oil- and water-producing wells included downhole and surface measurements (pump intake pressure, pump discharge pressure, vibration, intake temperature, motor temperature, passive and active current, motor frequency, and current, voltage). These data were transmitted, using satellite, to a real-time surveillance center that integrates them with additional information from different disciplines, including artificial lift, production, chemical treatment, facilities, maintenance, and secondary recovery.

Fully operational since 2016, this center provides the field with 24/7 support. There are two specific workflows executed by the surveillance center: the surveillance workflow aims to detect and solve abnormal ESP operation, and the optimization workflow aims to maximize oil production and achieve the objectives of the waterflooding strategy.

When any change in trend or anomaly during operation of the ESP system is detected, an alarm is immediately distributed, including prompt diagnostic and recommendations for preventive and corrective actions to avoid ESP failure and minimize downtime. These recommendations are tracked until their resolution.

TRIPLED ESP RUN LIFE DESPITE WATERFLOOD PRODUCTION CHANGES

The operator installed the extended-life ESP pumps in 65 wells, achieving an average run life above 600 days, despite the abrasive solids and production fluctuations during the waterflood optimization. Compared with the previous 200-day run life, this represents a three-fold improvement.

The use of downhole centrifugal solids separator reduced solids down to 27%. This technology is part of the strategy to face conditions of increased solids production.

Continuously optimized with the surveillance service, the extended-life pumps have managed production changes from an 83% decline in some wells to a 40% increase in others. Overall, the field experienced an average production improvement of 16%. The operator calculated the benefit of avoiding workovers and deferred production at $2.5 million.

The well-to-well configuration used for waterflooding implementation was replicated in 21 patterns after the significant savings in surface facilities. This enabled injection in 28 injector wells, reducing the investment by approximately $14 million and decreasing the deployment time from 9 to 4 months. At the time of writing, 100,000 bpd of water are produced and directly injected, consequently increasing oil production to 30,000 bpd.

Further, the use of a downhole centrifugal solids separator reduced solids down to 27%. This technology is part of the strategy to face conditions of increased solids production.

CONTINUED SUCCESS

The implementation of wide-range ESP systems helped increase ESP survivability and reduced the need for early workover interventions. Figure 5 shows the mean time between failure (MTBF) in the field, where the waterflooding project was fully implemented in November 2017. MTBF in the field increased from an average 370 days in 2016 to 760 days in 2020, a 105% increase. This is attributed to the improvements in design that enabled covering a wide production range, as well as the enhanced solids-handling capabilities of the new design. The significant reduction in workover intervention saved an estimated $4.5 million.

OVERALL SUCCESS IN ORIENTE BASIN

The applied integrated artificial lift strategy overcame challenges faced in waterflooding and from field maturity. The benefits included a significant increase in oil production, improved ESP reliability, and achievement of waterflooding objectives. The well-to-well methodology proved successful, with the rapid response in secondary recovery for the field, saving high costs in surface facilities. High-pressure flowlines, horizontal pumps, chemical treatment, and more were no longer required for effective artificial lift.

The inclusion of the wide-range ESP technology for both oil- and water-producing wells also managed the challenge of waterflooding recovery with uncertain rates. As a result, ESP survivability increased, and MTBF in the field doubled.

The surveillance workflow used in this project was a key part of the strategy to increase ESP reliability and reduce downtime. Together with the production optimization workflow, the solution maximized production and achieved the flowrates and downhole pressures required by the waterflooding strategy. WO

*Mark of Schlumberger.

REFERENCE

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ACKNOWLEDGEMENT

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JORGE LUIS VILLALOBOS LEON is the artificial lift domain champion for Ecuador, Peru and Colombia at Schlumberger. His main focus is implementing artificial lift system solutions for optimizing production and improving the efficiency and performance of artificially lifted wells. Mr. Villalobos received his electrical engineering degree from University of Zulia in Venezuela and has more than 15 years of experience. He is author and co-author of a number of SPE publications.

CARLOS REYES HILL is the asset performance system principal production engineer for the Shaya project in Ecuador. His main focus is optimizing production with artificial lift systems through his direct involvement in well intervention and planning, well candidate selection, and root-cause analysis. Mr. Hill is also the main evaluator of new technologies focused on improving the run life of artificial lift systems, and is responsible for economical assessments, including risk analysis for special projects. He obtained his mechanical engineering degree from Los Andes University and a specialization in operational reliability from Simon Bolivar University. With 25 years of industry experience, Mr. Hill is an author and co-author of various SPE papers and patents.

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